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VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97308-1088

Re: Docket No. UM 1911 Resource Value of Solar – Idaho Power Company's Order No. 19-022 Revised Compliance Filing

Dear Filing Center:

In compliance with Order No. 19-022, Idaho Power Company ("Idaho Power" or "Company") hereby submits for filing revised additional information associated with its resource value of solar ("RVOS") calculation. As directed by Order No. 19-022, on July 18, 2019, Idaho Power submitted to the Public Utility Commission of Oregon ("Commission") RVOS component values for generation capacity, transmission and distribution ("T&D") capacity deferral, and line losses expressed in 12-month by 24-hour ("12x24") blocks and rudimentary locational values for T&D capacity deferrals. Previously, on March 18, 2019, Idaho Power submitted revised RVOS calculations and a revised utility-scale RVOS calculation consistent with the Commission's direction provided in Order No. 19-022.

Subsequent to the July 18, 2019, filing, Commission staff ("Staff") and intervenors provided comments on the Company's filing and conducted workshops to discuss the methodology used to prepare the information included in the filing. At a November 9, 2020, workshop, the Company agreed to review its calculations and provide revised 12x24 expressions of generation and T&D capacity. The following discussion replaces in its entirety the information originally provided in the Company's July 18, 2019, filing.

Additionally, since the Company's March 18, 2019, RVOS filing, the Company has provided Staff with updates to two of the eleven RVOS elements to provide a more-up-to date RVOS value: First, based on further investigation by Staff of the methodology used by the utilities to develop their avoided transmission capacity values, the Company updated its marginal cost of transmission capacity deferral value from $6.03 to $7.08 per MWh (in 2019 dollars). This change is described at greater length in Staff's February 6, 2020, Decision Meeting Memo. Second, Idaho Power provided Staff with RVOS values presented in 2020 dollars. The following table presents Idaho Power's original March 18, 2019, filing values (in 2019 dollars) as well as its updated values to reflect the change in transmission capacity RVOS value (in 2019 dollars) and Staff's Decision Meeting Memo values (in 2020 dollars). Note, however, that the 12x24 blocks provided in this revised filing were developed using the original March 18, 2019, values.

Element	March 2019 Compliance Filing (2019$)	January 2020 Transmission Correction (2019$)	Staff Public Meeting Memo (2020$)
	In $ per MWh		
Energy	$28.77	$28.77	$28.77
Generation Capacity	10.55	10.55	**11.42**
T&D Capacity Deferral	6.03	**7.08**	7.23
Line Losses	2.33	2.33	2.33
Integration	-0.57	-0.57	-0.57
Administration	-5.80	-5.80	-5.80
Market Price Response	-0.02	-0.02	-0.02
Hedge Value	1.44	1.44	1.44
Environmental Compliance	0.00	0.00	0.00
RPS Compliance	0.00	0.00	0.00
Grid Services	0.00	0.00	0.00
RVOS Total Value	**$42.73**	**$43.78**	**$44.80**
Utility-Scale Proxy (excludes renewable tax credits)	**$47.16**	**$49.85**	**$50.51**

GENERATION CAPACITY 12X24 BLOCKS

As directed in Order No. 19-022, the Company has developed its pricing for generation capacity value shaped across 12x24 blocks to express the temporal value of system generation capacity need. In accordance with the order, these 12x24 blocks were not shaped by solar performance assumptions, but rather were shaped to reflect when avoided generation capacity is most useful to the system.

To develop these blocks, the Company utilized loss of load probability ("LOLP") data developed during its 2017 Integrated Resource Plan ("IRP") to create a 12x24 profile. A LOLP study is typically performed within the context of resource planning as a measure of reliability. For the 2017 IRP, the LOLP study reflected 500 annual iterations of random outages, indicating time periods when the loss of a unit (or units) would have likely resulted in a service outage. Within the context of the RVOS, this data can be applied to identify when capacity would be most useful to the system to alleviate loss of load conditions.

Table 1 below presents the results of the LOLP study. Each amount represents the percentage of the loss-of-load instances that occurred during that month-hour during the study. As can be seen from Table 1, June and July contain the largest portion, 49 percent, of the total LOLP hours occurring in the analysis. This result is consistent with the Company's highest load hours that occur during its summer peak. Additionally, the winter months December through February contribute 33 percent of the LOLP hours identified in the study.

Table 1 – Loss of Load Probability, 2017 Integrated Resource Plan

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	0.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
6	0.68%	0.48%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
7	1.25%	2.60%	0.00%	0.00%	0.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%
8	2.41%	3.47%	0.00%	0.19%	0.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	1.45%	2.51%	0.00%	0.10%	0.00%	0.00%	0.00%	0.00%	0.10%	0.00%	0.00%	0.00%
10	0.87%	0.00%	0.00%	0.39%	0.19%	0.00%	0.00%	0.00%	0.10%	0.00%	0.00%	0.00%
11	0.77%	0.00%	0.00%	0.39%	0.00%	0.00%	0.39%	0.00%	0.10%	0.00%	0.00%	0.10%
12	0.29%	0.00%	0.00%	0.39%	0.39%	0.19%	0.68%	0.00%	0.00%	0.00%	0.00%	0.00%
13	0.10%	0.00%	0.00%	0.10%	0.19%	0.10%	1.64%	0.00%	0.10%	0.00%	0.00%	0.00%
14	0.10%	0.00%	0.00%	0.19%	0.39%	0.48%	2.80%	0.19%	0.00%	0.00%	0.00%	0.00%
15	0.00%	0.00%	0.00%	0.29%	0.19%	0.96%	5.30%	0.68%	0.58%	0.00%	0.00%	0.00%
16	0.10%	0.00%	0.00%	0.48%	0.19%	1.06%	5.79%	1.35%	0.77%	0.00%	0.00%	0.00%
17	0.58%	0.10%	0.00%	0.29%	0.48%	2.51%	8.68%	1.16%	1.35%	0.00%	0.00%	0.10%
18	2.03%	2.22%	0.00%	0.48%	0.48%	1.06%	7.52%	0.96%	0.96%	0.00%	0.00%	0.10%
19	1.64%	3.18%	0.00%	0.39%	0.29%	1.54%	3.28%	0.48%	0.96%	0.00%	0.00%	0.10%
20	0.87%	1.25%	0.00%	0.10%	0.19%	0.87%	2.22%	0.19%	0.77%	0.00%	0.00%	0.19%
21	0.39%	1.35%	0.10%	0.19%	0.29%	0.48%	0.77%	0.19%	0.19%	0.00%	0.00%	0.00%
22	0.00%	0.58%	0.00%	0.19%	0.00%	0.19%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%
23	0.00%	0.00%	0.00%	0.00%	0.10%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	13.69%	**17.74%**	**0.10%**	**4.15%**	**3.76%**	**9.55%**	**39.15%**	**5.21%**	**5.98%**	**0.00%**	**0.00%**	**0.68%**

The intent of the 12x24 matrix is to value capacity according to when it is most useful to the Company's system. The Company is generation capacity-sufficient for a majority of the year and has low LOLP values during the majority of the hours—therefore additional capacity during those times would provide no capacity value to the Company's system. Further, the Company's peak load amounts are heavily concentrated in the summer months of June through August, primarily in afternoon through evening hours, when energy use for cooling coincides with use by agricultural customers to operate irrigation pumps. Other high-load hours occur during the winter when daylight hours are fewest and electricity is used for lighting and heating. At these times, additional generation capacity may be useful to the system. Additionally, the Company's minimum loads occur during the shoulder months in the spring and fall. During these times, additional generation capacity would provide relatively little value to the system.

Overall, 183 of the 288 hours in the 12x24 matrix had a zero LOLP. For the remaining 105 hours the LOLP varied from 0.10 percent to 8.68 percent.

In Idaho Power's July 18, 2019, filing of its 12x24 generation capacity matrix, the Company described a method of "flattening" the LOLP-based cost assignment to avoid highly concentrated cost assignments and to result in a more practical allocation of generation capacity costs. While the Company is not proposing such a methodology in this filing, it believes that such an approach may have merit in future applications of the RVOS model.

The Company's March 18, 2019, RVOS filing calculated the value of generation capacity to be \$10.55 per MWh, which was based on a marginal cost of generation capacity of \$81 per kW-year (in 2019 dollars) and a levelized cost of generation capacity of \$52.51 per kW-year as determined by the RVOS model. The following table allocates that \$52.51 per kw-year value of generation capacity over the 12x24 blocks based on the LOLP matrix above. In accordance with Order No. 19-022, these 12x24 blocks are not shaped by solar performance assumptions, but rather are shaped to reflect when avoided generation capacity is most useful to the system:

Table 2 – Generation Capacity Value pricing (in dollars per MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	3.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	11.47	9.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	21.30	48.98	0.00	0.00	3.28	0.00	0.00	0.00	0.00	0.00	0.00	1.64
8	40.96	65.31	0.00	3.39	3.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	24.58	47.16	0.00	1.69	0.00	0.00	0.00	0.00	1.69	0.00	0.00	0.00
10	14.75	0.00	0.00	6.77	3.28	0.00	0.00	0.00	1.69	0.00	0.00	0.00
11	13.11	0.00	0.00	6.77	0.00	0.00	6.55	0.00	1.69	0.00	0.00	1.64
12	4.92	0.00	0.00	6.77	6.55	3.39	11.47	0.00	0.00	0.00	0.00	0.00
13	1.64	0.00	0.00	1.69	3.28	1.69	27.85	0.00	1.69	0.00	0.00	0.00
14	1.64	0.00	0.00	3.39	6.55	8.47	47.52	3.28	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	5.08	3.28	16.93	90.12	11.47	10.16	0.00	0.00	0.00
16	1.64	0.00	0.00	8.47	3.28	18.62	98.31	22.94	13.54	0.00	0.00	0.00
17	9.83	1.81	0.00	5.08	8.19	44.02	147.46	19.66	23.70	0.00	0.00	1.64
18	34.41	41.72	0.00	8.47	8.19	18.62	127.80	16.38	16.93	0.00	0.00	1.64
19	27.85	59.86	0.00	6.77	4.92	27.09	55.71	8.19	16.93	0.00	0.00	1.64
20	14.75	23.58	0.00	1.69	3.28	15.24	37.68	3.28	13.54	0.00	0.00	3.28
21	6.55	25.40	1.64	3.39	4.92	8.47	13.11	3.28	3.39	0.00	0.00	0.00
22	0.00	10.88	0.00	3.39	0.00	3.39	1.64	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	1.64	1.69	0.00	0.00	0.00	0.00	0.00	0.00

T&D CAPACITY 12X24 BLOCKS

Order 19-022 also requires Idaho Power to express T&D capacity values across 12x24 blocks that do not assume solar performance, but instead allocate the T&D capacity value to reflect when avoided T&D capacity is most useful to the system, such as when T&D is most capacity constrained. It should be noted that the $6.03/MWh reflected in the Company's March 18, 2019, compliance filing is a combination of both distribution and transmission components. Because the distribution system is generally designed to meet more localized peaks and the transmission system is generally designed to meet broader system peaks, it is necessary to separately determine the temporal values of these components.

For the deferral of distribution, the Company developed two 12x24 matrices, one for portions of its Oregon system that are summer-peaking and one for portions of the Oregon system that peak in the winter. The division of transformers into two seasonal groups was important to determine when the distribution system is most constrained. Because Idaho Power's Oregon service area contains some transformers that peak in winter and others that peak in summer, if data were combined for all transformers, the resulting 12X24 matrix could potentially yield less meaningful results, as the relative sizes of the seasonal peaks would be muted by being included in the same average shape.

Therefore, to develop the matrices, the hourly data for each of the 30 transformers that serve load in Oregon was collected for the twelve months ended April 30, 2019. The load of each of the 30 transformers was arranged in a 12x24 matrix, and a monthly typical day was created by computing the median value of each clock hour of the month. The transformers were then placed into two groups, summer peaking and winter peaking, based on when their peak load occurred.

Within each group, the 12x24 matrix of each individual transformer was added to create a summer peaking and winter peaking 12x24 matrix. Each matrix was normalized by dividing each element of the matrix by the sum of all the values within the matrix. These two 12x24 matrices are below:

Table 3 – Distribution Capacity Value--Summer Peaking 12x24 matrix

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.0032	0.0033	0.0029	0.0025	0.0030	0.0033	0.0039	0.0037	0.0026	0.0026	0.0031	0.0033
1	0.0032	0.0032	0.0028	0.0024	0.0029	0.0032	0.0038	0.0036	0.0025	0.0026	0.0031	0.0033
2	0.0032	0.0032	0.0028	0.0024	0.0028	0.0031	0.0037	0.0035	0.0025	0.0026	0.0031	0.0033
3	0.0032	0.0032	0.0028	0.0024	0.0028	0.0031	0.0036	0.0034	0.0025	0.0025	0.0032	0.0033
4	0.0033	0.0033	0.0029	0.0025	0.0028	0.0031	0.0036	0.0034	0.0025	0.0026	0.0032	0.0034
5	0.0035	0.0035	0.0031	0.0026	0.0029	0.0031	0.0036	0.0035	0.0026	0.0027	0.0033	0.0035
6	0.0037	0.0037	0.0034	0.0029	0.0031	0.0032	0.0037	0.0036	0.0028	0.0030	0.0036	0.0037
7	0.0039	0.0039	0.0036	0.0031	0.0033	0.0033	0.0038	0.0037	0.0030	0.0032	0.0038	0.0039
8	0.0040	0.0039	0.0037	0.0031	0.0034	0.0035	0.0040	0.0038	0.0030	0.0032	0.0039	0.0039
9	0.0039	0.0039	0.0035	0.0031	0.0034	0.0036	0.0042	0.0039	0.0031	0.0032	0.0038	0.0039
10	0.0039	0.0039	0.0034	0.0030	0.0035	0.0037	0.0043	0.0041	0.0031	0.0032	0.0037	0.0039
11	0.0037	0.0038	0.0033	0.0030	0.0035	0.0038	0.0046	0.0043	0.0032	0.0031	0.0036	0.0038
12	0.0036	0.0037	0.0032	0.0029	0.0036	0.0039	0.0048	0.0044	0.0032	0.0031	0.0035	0.0037
13	0.0035	0.0037	0.0031	0.0029	0.0036	0.0040	0.0049	0.0045	0.0033	0.0031	0.0034	0.0037
14	0.0035	0.0036	0.0031	0.0029	0.0036	0.0041	0.0050	0.0046	0.0033	0.0030	0.0034	0.0036
15	0.0034	0.0035	0.0030	0.0028	0.0036	0.0041	0.0051	0.0048	0.0033	0.0030	0.0033	0.0036
16	0.0035	0.0035	0.0030	0.0029	0.0037	0.0042	0.0052	0.0048	0.0034	0.0030	0.0034	0.0037
17	0.0036	0.0036	0.0030	0.0028	0.0037	0.0042	0.0052	0.0049	0.0034	0.0030	0.0036	0.0038
18	0.0037	0.0038	0.0030	0.0028	0.0037	0.0042	0.0052	0.0048	0.0034	0.0030	0.0036	0.0039
19	0.0038	0.0038	0.0030	0.0029	0.0036	0.0041	0.0051	0.0047	0.0033	0.0031	0.0036	0.0038
20	0.0037	0.0037	0.0031	0.0029	0.0035	0.0040	0.0050	0.0046	0.0033	0.0031	0.0036	0.0038
21	0.0036	0.0036	0.0031	0.0029	0.0035	0.0039	0.0048	0.0045	0.0032	0.0029	0.0034	0.0037
22	0.0034	0.0035	0.0030	0.0028	0.0034	0.0038	0.0046	0.0042	0.0030	0.0028	0.0034	0.0036
23	0.0033	0.0034	0.0029	0.0026	0.0031	0.0036	0.0043	0.0040	0.0028	0.0027	0.0032	0.0034

Table 4–Distribution Capacity Value—Winter Peaking 12x24 matrix

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.0039	0.0038	0.0032	0.0026	0.0025	0.0026	0.0030	0.0030	0.0025	0.0030	0.0037	0.0039
1	0.0039	0.0037	0.0032	0.0025	0.0024	0.0025	0.0028	0.0028	0.0024	0.0029	0.0036	0.0039
2	0.0038	0.0037	0.0033	0.0025	0.0023	0.0024	0.0027	0.0027	0.0023	0.0029	0.0036	0.0039
3	0.0039	0.0037	0.0033	0.0026	0.0023	0.0024	0.0026	0.0027	0.0023	0.0029	0.0036	0.0039
4	0.0039	0.0038	0.0034	0.0026	0.0023	0.0024	0.0026	0.0027	0.0024	0.0030	0.0037	0.0039
5	0.0041	0.0039	0.0035	0.0028	0.0024	0.0025	0.0027	0.0027	0.0025	0.0032	0.0039	0.0041
6	0.0044	0.0042	0.0039	0.0030	0.0027	0.0027	0.0028	0.0029	0.0027	0.0035	0.0042	0.0043
7	0.0047	0.0045	0.0042	0.0033	0.0028	0.0028	0.0030	0.0030	0.0029	0.0037	0.0045	0.0045
8	0.0048	0.0046	0.0043	0.0033	0.0029	0.0029	0.0031	0.0032	0.0030	0.0038	0.0045	0.0047
9	0.0048	0.0045	0.0041	0.0033	0.0030	0.0030	0.0033	0.0033	0.0031	0.0038	0.0044	0.0046
10	0.0046	0.0043	0.0038	0.0032	0.0030	0.0031	0.0034	0.0034	0.0031	0.0037	0.0043	0.0046
11	0.0044	0.0042	0.0037	0.0031	0.0030	0.0031	0.0036	0.0035	0.0031	0.0036	0.0042	0.0044
12	0.0041	0.0040	0.0034	0.0030	0.0030	0.0032	0.0037	0.0036	0.0031	0.0035	0.0040	0.0043
13	0.0039	0.0039	0.0033	0.0030	0.0030	0.0032	0.0038	0.0037	0.0031	0.0034	0.0040	0.0042
14	0.0038	0.0038	0.0032	0.0029	0.0030	0.0033	0.0039	0.0038	0.0031	0.0033	0.0039	0.0041
15	0.0037	0.0038	0.0031	0.0029	0.0030	0.0033	0.0040	0.0039	0.0031	0.0033	0.0038	0.0041
16	0.0038	0.0039	0.0031	0.0028	0.0030	0.0034	0.0041	0.0040	0.0031	0.0033	0.0039	0.0042
17	0.0040	0.0040	0.0031	0.0029	0.0030	0.0034	0.0042	0.0040	0.0031	0.0033	0.0041	0.0045
18	0.0044	0.0042	0.0032	0.0030	0.0030	0.0034	0.0042	0.0040	0.0032	0.0034	0.0043	0.0046
19	0.0044	0.0042	0.0032	0.0030	0.0029	0.0033	0.0041	0.0039	0.0031	0.0035	0.0042	0.0045
20	0.0044	0.0042	0.0034	0.0030	0.0029	0.0032	0.0040	0.0038	0.0032	0.0035	0.0042	0.0045
21	0.0043	0.0042	0.0033	0.0031	0.0030	0.0032	0.0038	0.0037	0.0031	0.0034	0.0041	0.0044
22	0.0042	0.0040	0.0033	0.0029	0.0028	0.0031	0.0036	0.0034	0.0029	0.0033	0.0039	0.0042
23	0.0040	0.0039	0.0032	0.0027	0.0027	0.0028	0.0033	0.0031	0.0026	0.0031	0.0038	0.0041

The summer peaking matrix demonstrates that the most valuable resource to a summer peaking transformer would generate in July between 18:00 and 21:00, typically when air conditioning load coupled with irrigation load causes stress on the system during the late evening hours of July.

The winter peaking matrix shows a typical winter load shape with a double peak, one in the early hours of the day, around 8:00, and a late peak, around 19:00. Given that the transformers with winter peak loads also have summer peak loads, it can be seen that there is also a smaller peak during the month of July around 19:00.

As seen in the two matrices, a summer peaking transformer has different loading characteristics than a winter peaking transformer. Applying a summer load shape to a winter peaking transformer will not defer the upgrade of the transformer, nor will applying a winter load shape help defer the upgrade of a summer peaking transformer. Each transformer has its individual needs, which the Company has recognized through two different seasonal shapes as shown. Eventually, having a 12x24 matrix for each transformer may be more desirable given that each transformer has a unique loading characteristic based on its load and location, but an initial two-season matrix was the appropriate first step.

The Company's March 18, 2019, RVOS filing calculated the combined T&D capacity value of $6.03 per MWh based on deferral values of $12.99 per kW-year for distribution and $31.25 per kW-year for transmission (in 2019 dollars). The following tables allocate the distribution deferral value of $12.99 per kW-year, adjusted for assumed line losses over the summer-peaking and winter-peaking 12x24 blocks discussed above.

Table 5 – Distribution Capacity Summer-peaking resources-pricing (in dollars per MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	1.45	1.66	1.29	1.16	1.35	1.56	1.79	1.70	1.23	1.17	1.47	1.51
1	1.46	1.63	1.28	1.14	1.29	1.48	1.71	1.64	1.19	1.16	1.47	1.50
2	1.45	1.62	1.26	1.13	1.27	1.46	1.66	1.60	1.18	1.16	1.46	1.48
3	1.46	1.62	1.29	1.13	1.26	1.44	1.63	1.55	1.17	1.15	1.48	1.48
4	1.50	1.66	1.32	1.16	1.27	1.45	1.61	1.56	1.19	1.18	1.50	1.52
5	1.56	1.73	1.40	1.23	1.33	1.47	1.61	1.57	1.21	1.24	1.56	1.57
6	1.69	1.86	1.53	1.35	1.41	1.51	1.65	1.63	1.33	1.36	1.68	1.69
7	1.77	1.96	1.64	1.44	1.47	1.57	1.74	1.67	1.39	1.45	1.77	1.75
8	1.80	1.97	1.66	1.45	1.52	1.62	1.82	1.73	1.42	1.46	1.81	1.78
9	1.78	1.97	1.60	1.43	1.54	1.68	1.90	1.78	1.44	1.46	1.78	1.77
10	1.75	1.94	1.56	1.41	1.57	1.75	1.97	1.85	1.47	1.45	1.75	1.76
11	1.70	1.91	1.50	1.39	1.57	1.79	2.07	1.94	1.48	1.42	1.69	1.73
12	1.65	1.86	1.46	1.37	1.62	1.84	2.17	2.00	1.51	1.40	1.65	1.68
13	1.60	1.83	1.42	1.37	1.64	1.87	2.21	2.04	1.52	1.39	1.61	1.66
14	1.58	1.80	1.39	1.35	1.63	1.90	2.28	2.09	1.53	1.37	1.58	1.63
15	1.55	1.76	1.36	1.33	1.65	1.92	2.33	2.16	1.56	1.35	1.55	1.62
16	1.56	1.77	1.35	1.34	1.67	1.96	2.36	2.19	1.58	1.35	1.57	1.67
17	1.64	1.81	1.34	1.33	1.67	1.97	2.36	2.20	1.60	1.35	1.66	1.73
18	1.68	1.89	1.35	1.33	1.66	1.95	2.37	2.18	1.59	1.36	1.70	1.74
19	1.70	1.90	1.35	1.34	1.63	1.92	2.32	2.13	1.56	1.40	1.68	1.72
20	1.67	1.87	1.40	1.36	1.59	1.88	2.28	2.09	1.56	1.41	1.66	1.70
21	1.64	1.82	1.40	1.35	1.60	1.84	2.19	2.02	1.49	1.33	1.61	1.68
22	1.56	1.75	1.34	1.29	1.52	1.77	2.10	1.92	1.39	1.27	1.58	1.62
23	1.48	1.69	1.30	1.22	1.42	1.67	1.95	1.79	1.31	1.21	1.51	1.56

Table 6: Distribution Capacity-Winter-peaking resources-pricing (in dollars per MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	1.77	1.89	1.46	1.21	1.11	1.23	1.36	1.34	1.17	1.35	1.73	1.78
1	1.75	1.87	1.45	1.18	1.07	1.17	1.28	1.28	1.12	1.33	1.70	1.77
2	1.74	1.87	1.48	1.18	1.05	1.15	1.24	1.24	1.10	1.33	1.70	1.76
3	1.75	1.87	1.51	1.20	1.04	1.13	1.20	1.21	1.09	1.33	1.71	1.76
4	1.78	1.90	1.54	1.23	1.05	1.12	1.19	1.21	1.12	1.37	1.74	1.79
5	1.85	1.95	1.61	1.30	1.10	1.16	1.21	1.24	1.17	1.43	1.82	1.84
6	1.98	2.11	1.75	1.43	1.21	1.25	1.27	1.31	1.27	1.57	1.96	1.94
7	2.11	2.24	1.90	1.56	1.28	1.31	1.34	1.35	1.37	1.68	2.09	2.05
8	2.16	2.30	1.95	1.55	1.33	1.37	1.41	1.44	1.42	1.74	2.13	2.12
9	2.15	2.27	1.84	1.54	1.35	1.41	1.49	1.49	1.44	1.73	2.08	2.10
10	2.07	2.18	1.72	1.50	1.36	1.45	1.56	1.54	1.43	1.68	2.03	2.07
11	1.98	2.12	1.66	1.45	1.36	1.47	1.64	1.59	1.44	1.64	1.97	2.01
12	1.84	2.02	1.54	1.39	1.35	1.49	1.69	1.64	1.44	1.58	1.88	1.97
13	1.77	1.95	1.48	1.38	1.36	1.51	1.73	1.68	1.46	1.55	1.85	1.90
14	1.71	1.92	1.44	1.36	1.36	1.53	1.79	1.72	1.47	1.51	1.81	1.84
15	1.70	1.90	1.39	1.34	1.35	1.55	1.83	1.76	1.44	1.49	1.80	1.86
16	1.72	1.96	1.40	1.33	1.36	1.58	1.88	1.81	1.46	1.50	1.83	1.91
17	1.83	2.01	1.41	1.34	1.36	1.59	1.92	1.82	1.47	1.51	1.92	2.02
18	1.99	2.10	1.44	1.39	1.37	1.61	1.92	1.83	1.49	1.55	2.01	2.08
19	2.00	2.10	1.45	1.39	1.33	1.56	1.86	1.78	1.46	1.59	1.97	2.05
20	1.99	2.11	1.52	1.40	1.33	1.52	1.80	1.72	1.49	1.59	1.95	2.02
21	1.96	2.08	1.51	1.43	1.35	1.48	1.73	1.66	1.45	1.55	1.90	1.98
22	1.89	2.01	1.48	1.35	1.29	1.45	1.65	1.56	1.35	1.47	1.84	1.92
23	1.82	1.95	1.47	1.26	1.20	1.33	1.50	1.42	1.24	1.40	1.77	1.84

With regard to transmission, the Company would like to reiterate its position that the deferred transmission value for its Oregon RVOS should be $0.00. With respect to new solar facilities, the Company's system in Oregon is winter peaking (at approximately 8 a.m.) and with the lack of sunlight a new solar resource would not be able to meaningfully decrease the Oregon system peak and defer any transmission investment. With regard to non-solar resources, the Company already purchases a relatively large amount of generation from facilities sited in Oregon relative to retail Oregon load. In total, the Company purchases the output of 240 MW nameplate capacity of third-party generation, mostly intermittent, relative to an average load of 77 MW (calendar year 2018). Given these values, the addition of new intermittent resources located in Oregon would not defer any transmission investment, but rather would likely result in the need for incremental transmission investment. However, to comply with the Commission's order, the Company has left the transmission deferral value of $31.25 / kW-year unchanged from its March 18, 2019, compliance filing.

The Company assigned values to the 12x24 matrix based on Oregon net load, by combining a 12x24 matrix of the annual output of the intermittent generation resources with a 12x24 matrix totaling the load of all transformers serving load in Oregon. All of the negative elements in the matrix were set to a fixed non-zero value, and the matrix was converted to the scalar matrix below based on the relative values in the net load matrix. This method is necessary given the unique characteristics of Idaho Power's Oregon transmission system. Given the high ratio of intermittent generation to retail load, the potentially negative impact to the Company's system is less when load relative to intermittent generation is higher. Therefore, this method sends the appropriate signal to new projects by assigning transmission value to time periods that will be least likely to result in increased transmission cost.

Table 7 – Transmission Capacity Value 12x24 matrix

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.500	0.500	3.895	0.500	0.500	0.500	0.500	0.500	0.500	1.476	5.895	0.500
1	0.500	0.500	4.325	0.500	0.500	0.500	0.500	0.500	0.500	2.755	3.576	0.500
2	2.111	0.500	3.672	0.500	0.500	0.500	0.500	0.500	0.500	0.500	2.839	0.500
3	0.500	0.500	4.202	0.500	0.500	0.500	0.500	0.500	0.500	2.460	0.500	0.500
4	0.500	0.500	2.120	0.500	0.500	0.500	0.500	0.500	0.500	5.342	0.500	0.500
5	0.500	0.500	1.380	0.500	0.500	0.500	0.500	0.500	0.500	4.381	0.500	0.500
6	1.803	0.500	1.762	0.500	0.500	0.500	0.500	0.500	0.500	5.937	0.160	0.500
7	0.500	0.500	5.132	0.500	0.500	0.500	0.500	0.500	0.500	5.693	0.290	0.500
8	0.500	0.500	2.519	0.500	0.500	0.500	0.500	0.500	0.500	5.812	0.500	0.500
9	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500
10	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500
11	0.500	0.500	0.500	0.500	0.500	0.500	0.101	0.500	0.500	0.500	0.500	0.500
12	0.500	0.500	0.500	0.500	0.500	0.500	1.525	0.418	0.500	0.500	0.500	0.500
13	0.500	0.500	0.500	0.500	0.500	0.500	0.511	3.093	0.500	0.500	0.500	0.500
14	0.500	0.500	0.500	0.500	0.500	0.500	2.680	4.975	0.500	0.500	0.500	0.500
15	0.500	0.500	0.500	0.500	0.500	0.500	4.684	4.345	0.500	0.500	0.500	0.500
16	0.500	0.500	0.500	0.500	0.500	0.500	3.921	2.957	0.500	0.500	0.500	0.500
17	0.500	0.500	0.500	0.500	0.500	0.500	0.520	0.108	0.500	0.500	0.500	0.500
18	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500
19	0.500	0.500	4.976	0.500	0.500	0.500	0.500	0.500	0.500	3.165	3.618	0.500
20	0.500	0.500	8.585	0.500	0.500	0.500	0.500	0.500	0.500	5.238	2.648	0.500
21	0.500	0.500	4.899	0.500	0.500	0.500	0.500	0.500	0.500	5.183	1.762	0.500
22	0.500	0.500	3.606	0.500	0.500	0.500	0.500	0.500	0.500	4.739	1.132	0.500
23	0.500	0.500	2.563	0.500	0.500	0.500	0.500	0.500	0.500	3.582	5.004	0.500

The Company's March 18, 2019, RVOS filing calculated the combined T&D capacity value of $6.03 per MWh based on the relative deferral values of $12.99 per kW-year for distribution and $31.25 per kW-year for transmission. The following table allocates the transmission deferral value of $31.25 per kw-year, adjusted for line losses, over the 12x24 matrix:

Table 8 – Transmission Capacity pricing (in dollars per MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	1.91	1.91	14.92	1.91	1.91	1.91	1.91	1.91	1.91	5.65	22.57	1.91
1	1.91	1.91	16.56	1.91	1.91	1.91	1.91	1.91	1.91	10.55	13.69	1.91
2	8.08	1.91	14.06	1.91	1.91	1.91	1.91	1.91	1.91	1.91	10.87	1.91
3	1.91	1.91	16.09	1.91	1.91	1.91	1.91	1.91	1.91	9.42	1.91	1.91
4	1.91	1.91	8.12	1.91	1.91	1.91	1.91	1.91	1.91	20.46	1.91	1.91
5	1.91	1.91	5.28	1.91	1.91	1.91	1.91	1.91	1.91	16.78	1.91	1.91
6	6.90	1.91	6.75	1.91	1.91	1.91	1.91	1.91	1.91	22.73	0.61	1.91
7	1.91	1.91	19.65	1.91	1.91	1.91	1.91	1.91	1.91	21.80	1.11	1.91
8	1.91	1.91	9.65	1.91	1.91	1.91	1.91	1.91	1.91	22.25	1.91	1.91
9	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91
10	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91
11	1.91	1.91	1.91	1.91	1.91	1.91	0.39	1.91	1.91	1.91	1.91	1.91
12	1.91	1.91	1.91	1.91	1.91	1.91	5.84	1.60	1.91	1.91	1.91	1.91
13	1.91	1.91	1.91	1.91	1.91	1.91	1.96	11.84	1.91	1.91	1.91	1.91
14	1.91	1.91	1.91	1.91	1.91	1.91	10.26	19.05	1.91	1.91	1.91	1.91
15	1.91	1.91	1.91	1.91	1.91	1.91	17.94	16.64	1.91	1.91	1.91	1.91
16	1.91	1.91	1.91	1.91	1.91	1.91	15.01	11.32	1.91	1.91	1.91	1.91
17	1.91	1.91	1.91	1.91	1.91	1.91	1.99	0.41	1.91	1.91	1.91	1.91
18	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91
19	1.91	1.91	19.05	1.91	1.91	1.91	1.91	1.91	1.91	12.12	13.85	1.91
20	1.91	1.91	32.87	1.91	1.91	1.91	1.91	1.91	1.91	20.06	10.14	1.91
21	1.91	1.91	18.76	1.91	1.91	1.91	1.91	1.91	1.91	19.85	6.75	1.91
22	1.91	1.91	13.81	1.91	1.91	1.91	1.91	1.91	1.91	18.15	4.33	1.91
23	1.91	1.91	9.81	1.91	1.91	1.91	1.91	1.91	1.91	13.71	19.16	1.91

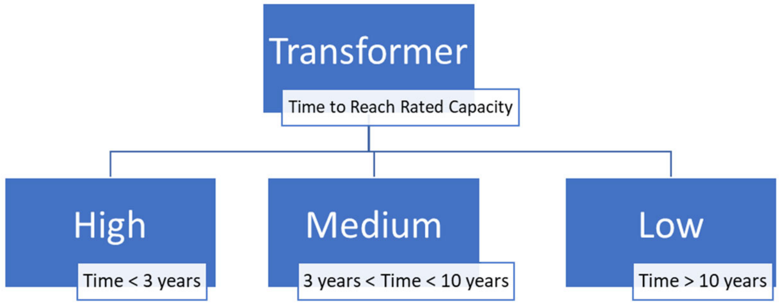
T&D LOCATIONAL CAPACITY DEFERRAL VALUE

Idaho Power also has developed a methodology to determine locational pricing for T&D capacity deferrals. As discussed above, there are currently no transmission-related projects in Oregon that the Company believes could be deferred through the use of sited generation. Therefore, this discussion focuses on the ability to defer distribution-related investments.

The Company's locational capacity deferral value analysis was focused on substation transformers, given that these assets are usually the limiting factor in a distribution system. The Company collected data for each of the 30 substation transformers that serve load in Oregon including:

- Transformer name
- Rated capacity
- Peak load
- Growth rate

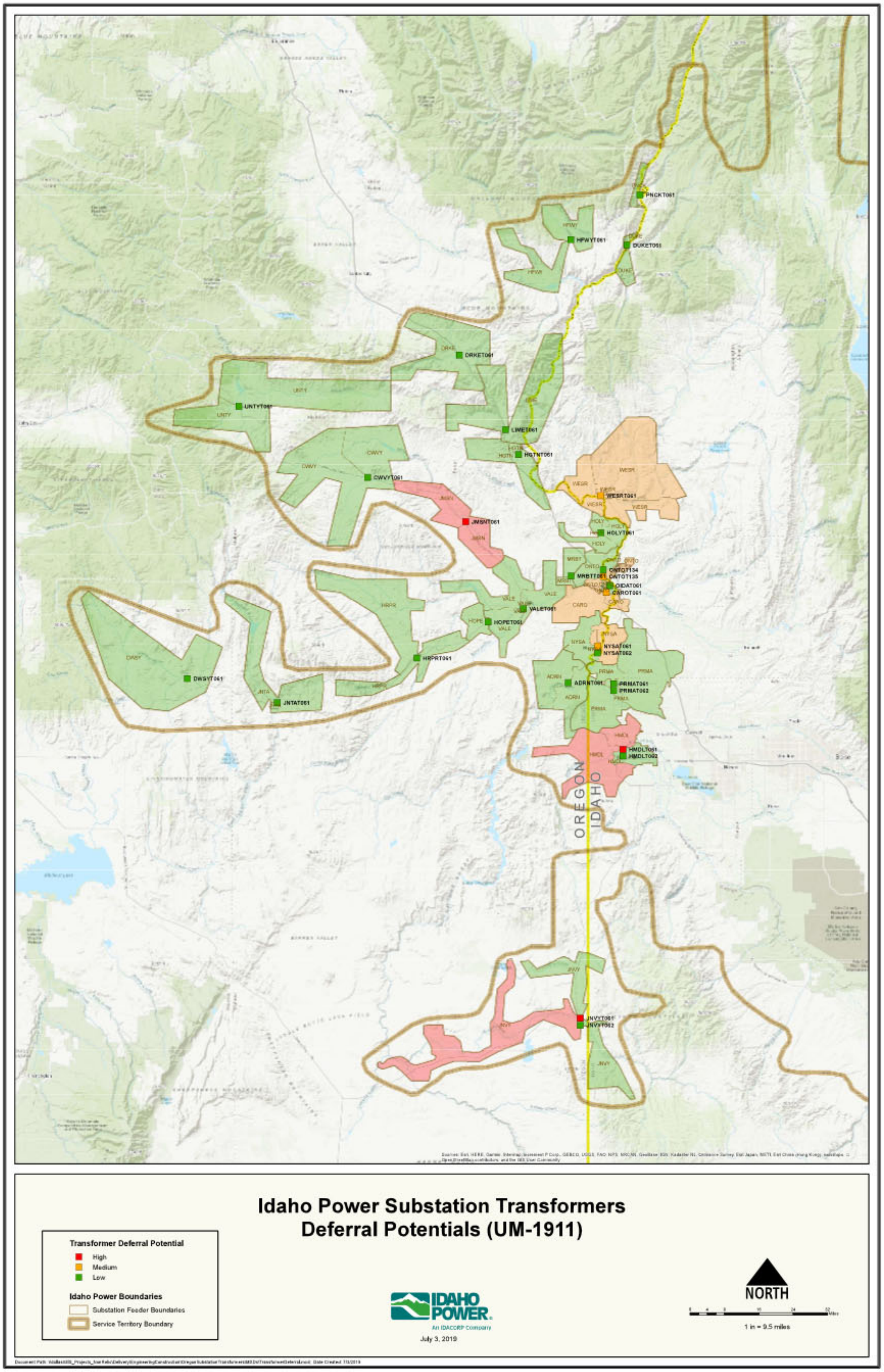
The number of years needed to reach the rated capacity of each transformer was calculated using the transformer rated capacity, the transformer peak load, and the transformer load growth rate. Each transformer was given the label of high-, medium- or low-value depending on the number of years before each reaches its rated capacity, as follows:



The results of the transformer-by-transformer analysis are shown in the table below.

Transformer	Summer Planning Capacity Limit (MW)	Summer Peak Load (MW)	Summer Growth Rate	Winter Planning Capacity Limit (MW)	Winter Peak Load (MW)	Winter Growth Rate	Season	Overall Growth Rate	Years to 100%	H/M/L
CAROT061	19.60	18.29	1.65%	22.00	13.89	1.65%	Summer	1.65%	4.34	M
HMDLT061	13.72	9.34	1.86%	15.40	15.34	3.28%	Winter	3.28%	0.12	H
JMSNT061	4.90	4.62	3.85%	5.50	2.64	3.85%	Summer	3.85%	1.57	H
JNVYT061	1.97	1.96	1.01%	2.21	1.38	1.09%	Summer	1.01%	0.51	H
ONTOT135	36.58	34.30	1.01%	41.06	16.13	1.01%	Summer	1.01%	6.58	M
PRMAT062	33.32	22.15	2.45%	22.00	12.65	2.45%	Summer	2.45%	20.58	L
WESRT061	13.72	12.67	1.74%	15.40	11.12	1.74%	Summer	1.74%	4.76	M
HFWYT061	6.54	3.74	1.32%	7.34	5.95	0.80%	Winter	0.80%	29.16	L
HMDLT062	N/A	N/A	N/A	22.00	17.27	1.40%	Winter	1.40%	19.61	L
HOLYT061	9.19	7.19	2.06%	10.32	5.18	2.06%	Summer	2.06%	13.50	L
NYSAT061	13.72	11.94	1.93%	15.40	12.33	1.93%	Summer	1.93%	7.72	M
OIDAT061	27.44	22.81	0.50%	30.80	22.90	0.50%	Summer	0.50%	40.60	L
ONTOT134	29.40	22.28	2.15%	33.00	20.53	2.15%	Summer	2.15%	14.86	L
VALET061	13.72	11.36	1.77%	15.40	10.28	1.77%	Summer	1.77%	11.74	L
ADRNT061	10.29	4.44	1.23%	11.55	4.82	0.93%	Summer	1.23%	107.18	L
CWVYT061	3.43	2.21	0.76%	3.85	2.18	0.00%	Summer	0.76%	72.44	L
DRKET061	0.97	0.41	2.28%	1.09	0.50	2.28%	Winter	2.28%	51.75	L
DUKET061	5.64	0.11	0.00%	6.34	0.10	0.00%	Summer	0.00%	-	L
DWSYT061	0.97	0.44	0.37%	1.09	0.55	0.37%	Winter	0.37%	265.36	L
HGTNT061	3.43	0.94	3.43%	3.85	0.91	3.43%	Summer	3.43%	77.23	L
HOPET061	6.54	3.36	0.25%	7.34	2.59	1.08%	Summer	0.25%	374.30	L
HRPRT061	3.43	1.39	0.61%	3.85	1.86	0.00%	Winter	0.00%	-	L
JNTAT061	0.65	0.22	0.00%	0.73	0.41	0.00%	Winter	0.00%	-	L
JNVYT062	1.47	0.55	1.60%	1.65	0.63	1.34%	Winter	1.34%	120.82	L
LIMET061	3.43	0.32	0.00%	3.85	0.30	0.00%	Summer	0.00%	-	L
MRBTT061	10.29	6.41	0.33%	11.55	3.19	0.40%	Summer	0.33%	182.61	L
NYSAT062	13.72	8.36	3.22%	15.40	5.63	3.22%	Summer	3.22%	19.91	L
PNCKT061	1.47	0.52	1.85%	1.65	0.29	1.85%	Summer	1.85%	98.75	L
PRMAT061	13.72	7.33	1.95%	15.40	8.46	1.95%	Winter	1.95%	42.07	L
UNTYT061	3.43	1.68	4.16%	3.85	1.40	4.16%	Summer	4.16%	25.04	L

Based on these rankings, locational capacity deferral value would be assigned to those transformers that provide at least a medium deferral value. The magnitude and method of developing actual values, as well as the interaction between the locational values and the 12x24 transmission and distribution capacity matrix values will require additional analysis. The Company has discussed potential next steps with Commission Staff and looks forward to further collaboration to discuss how these temporal and locational values will be combined with other analyses performed within this docket to develop a meaningful and practical RVOS. A map of the Company's Oregon service territory showing the locational values is presented below:


PNCKT061
HPWYT061
DUKET061
DRKET061
UNTYT061
LIMET061
HGTNT061
CWVYT061
WESRT061
JMSNT061
HOLYT061
MRBTT061
VALET061
HOPET061
NYSAT061
NYSAT062
HRPRT061
ADRNT061
PRMAT061
PRMAT062
DWSYT061
JNTAT061
HMDLT061
HMDLT062
JNVYT061
JNVYT062
OREGON
IDAHO
Idaho Power Substation Transformers
Deferral Potentials (UM-1911)
Transformer Deferral Potential
High
Medium
Low
Idaho Power Boundaries
Substation Feeder Boundaries
Service Territory Boundary
IDAHO POWER.
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July 3, 2019
NORTH
1 in = 9.5 miles

LINE LOSSES 12X24 BLOCKS

For the expression of line loss value on a 12x24 basis, the Company applied the transmission 12x24 matrix provided above in Table 8 to the calculated line loss value of $2.33 per MWh from the Company's March 18, 2019, RVOS filing. As described in the transmission discussions above, the Company already purchases a relatively large amount of generation from facilities sited in Oregon relative to retail load. The addition of new intermittent resources in Oregon would not reduce line losses, but rather would likely result in additional line losses during times of excess generation as reflected in Table 7.

The following table allocates the $2.33 per MWh line loss value from the March 18, 2019, filing across the transmission 12x24 matrix in Table 7:

Table 9 – Line loss pricing (in dollars per MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	1.16	1.16	9.08	1.16	1.16	1.16	1.16	1.16	1.16	3.44	13.73	1.16
1	1.16	1.16	10.08	1.16	1.16	1.16	1.16	1.16	1.16	6.42	8.33	1.16
2	4.92	1.16	8.56	1.16	1.16	1.16	1.16	1.16	1.16	1.16	6.62	1.16
3	1.16	1.16	9.79	1.16	1.16	1.16	1.16	1.16	1.16	5.73	1.16	1.16
4	1.16	1.16	4.94	1.16	1.16	1.16	1.16	1.16	1.16	12.45	1.16	1.16
5	1.16	1.16	3.21	1.16	1.16	1.16	1.16	1.16	1.16	10.21	1.16	1.16
6	4.20	1.16	4.11	1.16	1.16	1.16	1.16	1.16	1.16	13.83	0.37	1.16
7	1.16	1.16	11.96	1.16	1.16	1.16	1.16	1.16	1.16	13.26	0.68	1.16
8	1.16	1.16	5.87	1.16	1.16	1.16	1.16	1.16	1.16	13.54	1.16	1.16
9	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16
10	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16
11	1.16	1.16	1.16	1.16	1.16	1.16	0.23	1.16	1.16	1.16	1.16	1.16
12	1.16	1.16	1.16	1.16	1.16	1.16	3.55	0.97	1.16	1.16	1.16	1.16
13	1.16	1.16	1.16	1.16	1.16	1.16	1.19	7.21	1.16	1.16	1.16	1.16
14	1.16	1.16	1.16	1.16	1.16	1.16	6.24	11.59	1.16	1.16	1.16	1.16
15	1.16	1.16	1.16	1.16	1.16	1.16	10.91	10.12	1.16	1.16	1.16	1.16
16	1.16	1.16	1.16	1.16	1.16	1.16	9.14	6.89	1.16	1.16	1.16	1.16
17	1.16	1.16	1.16	1.16	1.16	1.16	1.21	0.25	1.16	1.16	1.16	1.16
18	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16
19	1.16	1.16	11.59	1.16	1.16	1.16	1.16	1.16	1.16	7.38	8.43	1.16
20	1.16	1.16	20.00	1.16	1.16	1.16	1.16	1.16	1.16	12.21	6.17	1.16
21	1.16	1.16	11.41	1.16	1.16	1.16	1.16	1.16	1.16	12.08	4.11	1.16
22	1.16	1.16	8.40	1.16	1.16	1.16	1.16	1.16	1.16	11.04	2.64	1.16
23	1.16	1.16	5.97	1.16	1.16	1.16	1.16	1.16	1.16	8.35	11.66	1.16

SUMMARY

As discussed above, in this revised compliance filing Idaho Power has provided revisions to the 12x24 information required by Order No. 19-022, which also addresses concerns raised by Staff and intervenors during the comment period and public workshops. The Company has provided revised 12x24 RVOS blocks for generating capacity, T&D capacity and line losses, as well as providing information regarding the development of locational values of T&D capacity. The Company has described the methodology it used to calculate the 12x24 blocks, discussed how each 12x24 matrix reflects system need, and provided workpapers supporting the calculations. Idaho Power believes that the 12x24 blocks provided herein provide a reasonable representation of system needs and can be used as a basis to develop RVOS values that achieve the Commission's goal to establish a framework to express the quantifiable costs and benefits of bringing solar resources to the utility's system and its desire to develop more granular expressions of resource value, thus improving techniques for valuing resource benefits.

Sincerely,

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